

Scenarios for Data Exchange using Standards IEC 61970 and IEC 61850

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Abstract—Intelligent Electronic Devices in substations (such as Digital Fault Recorders, Digital Protective Relays, and Circuit Breaker Monitors) provide nowadays access to much more information. This could be used at the control centre to improve its applications (such as the topology processing and state estimation), by making them faster, more robust and more reliable. Two recently adopted standards define data interchange within substations (IEC 61850) and with control centres (IEC 61970). We show how these standards can be used to provide a control centre’s application access to IED data, even if the two standards do not share the same data model.

Index Terms—Substation Automation System (SAS), IEC 61850, Substation Configuration description Language (SCL), Energy Management System (EMS), IEC 61970, Common Information Model (CIM), CIMXML, data exchange, State Estimation (SE), Topology Processing (TP)

I. INTRODUCTION

LARGELY historically motivated, but also for the purpose of reliability and due to the importance of their functions, utility control centre and substation systems were generally developed as closed systems. The data exchange between the two has the following characteristics:

- Communications-wise, the data exchange is most often based on a number of proprietary communications protocols.
- Contents-wise, the amount of data sent from substations is brought to the necessary minimum for control centre applications to perform.

The capacity of communications links with high reliability requirements, were (and still are) the main limiting factor with respect to the amount of data exchanged. Topology processing (TP) and state estimation (SE) applications of the control centre typically rely on switch statuses and rms values of observable measurements, and are responsible for creating an “image” of the network from that scarce substation data, as required for the control centre EMS applications.

With the developments in different technology areas, such as Intelligent Electronic Devices (IED), advanced algorithms for both substation and control centre applications, and the emergence of formal, standardised application data semantics, it is nowadays possible to reconsider the data exchange between the utility control centre and substation control system, while complying with the physical limitations of the (installed) communications infrastructure.

Two recently adopted standards are related to data interchange within substations (IEC 61850 [1]) and between control centres (IEC 61970 [2]). The system vendors already provide first implementations of parts of the specifications; but more importantly, utilities require conformance to them in their current invitation for tenders. However, despite the similar application domain (electrical utility control systems) and the foreseeable future integration requirements of EMS with SAS applications, the development of the two standards progressed unfortunately quite independently. Consequently, the question of mapping between the two standards and their data models arises [3].

This paper addresses different integration scenarios of control centre and substation control systems, based on IEC 61870 and IEC 61850, motivated by the future implementation of new monitoring and control applications using IED data acquired in substations. The paper first briefly introduces such an application. An overview of the two standards with a mapping example is discussed, followed by scenarios for realising the required data exchange. Conclusions and references are given at the end.

II. APPLICATION: RELIABLE SUBSTATION TOPOLOGY

This section briefly introduces an approach to advanced processing of data from different substation IEDs, such as Digital Fault Recorders, Digital Protective Relays, and Circuit Breaker Monitors [5]. The results of this processing can benefit the standard TP and SE applications of the control centre’s SCADA system, making them faster, more robust and reliable [4]. These two SCADA applications are essential, as they provide the “image” of the underlying substations to the control centre EMS applications – not only those that run regularly (in the background), but also to those applications that the operators use to monitor and control the power system in normal, emergency and restorative states.

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The emergency states in the power system are handled, in the first place, by protective relays. In the past, they were of an electromechanical design, and did not have any “intelligence” – the raw signals used to be passed to the Remote Terminal Units (RTU), which contained the logic for interpreting, for instance, switch positions and to calculate the rms values for voltages and powers out of the 3-phase measurements. These are typically the only kind of data that the RTUs communicate from the substation to the control centre SCADA.

Development of microprocessor-based devices, IEDs, not only enabled complex protection and control algorithms to be run on the devices themselves, but also enabled the communication with these devices. It is therefore possible to obtain different kinds of data that the IEDs record, and to apply advanced data processing techniques, both in real-time (i.e., during operation), and off-line, for analysis purposes.

To illustrate the benefit from having access to the data available from IEDs in substations, consider the following types of IEDs and the data they can provide, related to circuit breaker operation:

- Protective relays provide duty cycle currents, I^2t
- Digital fault recorders provide “a” and “b” contacts and phase current changes;
- Circuit breaker monitors provide control circuit signals, vibration and gas pressure;

Different advanced data processing techniques can be applied to the above data, such as temporal analysis or historical assessment, in order to obtain different kinds of more reliable information about a breaker’s operation. Two of these techniques, with an outcome relevant in the context of reliable substation topology, are shown in Table I: (a) use of redundant data, and, (b) correlation among different data.

TABLE I – MEANS OF OBTAINING RELIABLE TOPOLOGY INFORMATION

Redundant Data	Data Correlation
Multiple IEDs measure CB status and analogues	Interpreting CB cause-effect sequences
Confirming CB status based on multiple indications of the status	Making relationship between status changes and changes in analogues

The ability to provide highly reliable status and measurand information, as processed within the substation, can highly simplify the existing TP and SE applications at the control centre SCADA, and improve their own reliability and performance, with respect to all the other EMS applications.

In the following, we discuss the IEC standards, the data exchange scenarios, and the implications for existing substation and control centre systems.

III. OVERVIEW OF IEC 61850 AND IEC 61970

There are at least two aspects of the specifications in IEC 61850 and IEC 61970 standards:

- (1) The application data semantics, such as the meaning of circuit breaker and its position;
- (2) The information exchange, i.e., how actual data

instances can be exchanged. This point can further be subdivided, as a function of what information and in what environment it is to be exchanged:

(2.a) The configuration data exchange with help of, e.g., a file following a given serialisation format. The example would be an XML document describing the circuit breaker with its nameplate data, the information about what primary device it is protecting, and its normal position (open or close); and,

(2.b) The run-time application data exchange through an implementation of, e.g., the application programming interface (API) specified in a given programming language and/or services of the application layer of a given communications stack. The examples for this kind of exchange would be reading the current position of a circuit breaker, or an EMS operator command or protection function trip to change the breaker’s position at run-time.

Table II summarises the main characteristics of the two IEC standards, some of which are discussed below.

TABLE II – COMPARISON OF THE TWO IEC STANDARDS

	IEC 61850	IEC 61970
Control system domain	SAS	EMS
IT system domain	Substation <i>intra-apps</i>	Control centre <i>intra-apps</i>
Data model (1)	Yes	Yes (CIM)
Serialisation format	Yes (SCL) (2.a)	Yes (CIMXML) (2.a and 2.b)
Communications stack	Yes (2.b)	No
APIs	No	Yes (2.a and 2.b)

A. IEC 61850

“IEC 61850: Communications Networks and Systems in Substations” [1] is a communications standard, with the scope of applications within the substation domain. Its objective is to enable the interoperability of Intelligent Electronic Devices (IED) within the substation. The communications include the so-called substation bus (substation LAN), process bus (bus-oriented link to the I/Os), and peer-to-peer hard real-time communications between devices. The standard specifies Abstract Communication Service Interfaces (ACSI) and their mappings to concrete communications protocols (e.g., Manufacturing Message Specification, MMS).

In addition, IEC 61850 defines quite an elaborate data model for the substation domain, and a configuration data exchange format as an XML Schema [6][7], called Substation Configuration description Language (SCL). The only part of the standard that is specified in an electronically processable manner is the SCL, while the domain data and the services to access them are defined in text and tables. To circumvent this deficiency, and to be able to model mappings [3] of similar concepts between the IEC 61850 data model and that of IEC 61970, we have developed a formal model [8] using the *de facto* standard in software engineering, Unified Modelling Language (UML) [9].

The most notable concept with respect to the domain data model in IEC 61850 is that of *Logical Nodes* (LN). LNs model

either some atomic protection and control function typically allocated to an IED (e.g., under-voltage or synchro-check function), or play the role of a proxy for primary equipment (e.g., circuit breaker or measurement transformer). It is LNs that hold different (standardised) data items, necessary to perform the mentioned atomic function. Data of LNs are, in turn, domain specific abstract data types, with several nesting levels. When “unfolded” down to the primitive data types (like integers and booleans), the paths formed with the LN and its data could be seen as standardised “signal names”. For instance, circuit breaker number 3 is modelled by an LN of type XCBR. Then, XCBR3.Pos.stVal is a read-only data point, which represents the status signal of the position of the breaker; XCBR3.PosctlVal is a write-only control signal that allows one to change the position of the breaker; XCBR3.Pos.sboTimeout is the configuration parameter related to the select-before-operate mode of breaker control; and XCBR3.EEHealth.stVal is the status of the health (condition) of the breaker.

The above example shows that the data contained in LNs is not only that for operation, but also configuration data. Their standardised names (and types), which carry domain semantics, provide a standard way for describing and addressing data of an IED, irrespective of the functions’ implementation internal to the IED. This enables interoperability of devices among different vendors, as soon as they provide the IEC 61850 view of their data and the ACSI services implementation for exchanging that data.

B. IEC 61970

“IEC 61970: Energy Management System Application Programming Interface (EMS-API)” [2] normalises a set of APIs for the manipulation of real-time critical, near real-time and historical EMS/SCADA data. The objective is to support the integration of independently developed applications between vendor specific EMS systems, or between an EMS system and other systems that are concerned with different aspects of power system operations, such as generation or distribution management. In contrast to IEC 61850, this specification does not impose any particular communications stack, but provides only the APIs in standard IDL. These APIs need to be implemented in a programming language of choice (e.g., Java, C#, CORBA), and run within an execution environment (such as J2EE or .NET) or invoked through Remote Procedure Call, Web Services or another messaging mechanism. Nowadays, the typical communication in these environments would be TCP/IP-based.

Similar to IEC 61850, this specification also defines an elaborate data model, the Common Information Model (CIM), and a configuration data exchange format. In contrast to the data model of IEC 61850, CIM is already defined in UML, and maintained as a Rational Rose™ model file, which can be browsed online at <http://www.cimuser.com>. The UML model itself and a part of its automatically generated documentation are normative standard documents [2]. The model is also used to automatically generate the CIMXML, which is an

application of the Resource Description Format (RDF) standard [10] to the CIM model. More about the usage of CIMXML can be found in [11]. CIMXML schema is the serialisation format of the CIM model, and to some extent the counterpart of SCL of IEC 61850 (CIM is however not limited to configuration data).

CIM specifies the structure and common semantics for data items that represent power system resources (e.g., a substation, a switch, or a transformer), their attributes (e.g., ampere rating for a breaker), and relationships (e.g., a transformer has two or more windings). It also defines some abstract concepts, such as Measurement and Control, which are a generic mechanism to model status and control data points (or signals), respectively. The definition of all the domain concepts is in an object-oriented way. This means that the responsibilities in the sense of “what I know of” (i.e., attributes) and “whom I know of” (i.e., associations or relationships with other types) are well spread around the types. Consequently, CIM model has many types and relationships. In turn, each type has relatively few attributes.

For instance, the CIM Measurement has relationships to MeasurementType and MeasurementValue. A number of Measurements can be attached to Terminal of conducting equipment, such as Breaker. The appropriate “path” through relationships of Measurement provides for definition of data points (or signals). Thus, the current position of the breaker number 3 would be defined with two data items: Breaker3.Terminal.Measurement.MeasurementType.name and Breaker3.Terminal.Measurement.MeasurementValue.value, while the breaker’s ampere rating (as configuration parameter) would be defined in Breaker3.ampRating. The “short path” name typically means that it is an attribute (as is the case for the latter), and not the relationship to another type.

The above example shows again that the common domain semantics standardise data exchange, irrespective of internal EMS/SCADA implementation models. It enables integration with EMS systems of different vendors, as soon as they provide the CIM view of their data and the implementation of IEC 61970 APIs for exchanging that data.

IV. DATA EXCHANGE: WHAT AND HOW

The most notable contribution of the both mentioned standards are their domain models, which define the data semantics for information exchange among the software applications within utility’s systems, both back-office applications and network operation applications.

The typical (simplified) communications architecture is shown in Figure 1, and is used to describe the topology data exchange scenarios. It shows three hierarchical levels: control centre, substation and process I/O (primary equipment). Two sample substation architectures are shown in the lower part of the figure: on the left side, nowadays predominant architecture with hard-wired process I/Os and protection and control devices into RTUs, and on the right side, a full-fledged SAS,

with bus-oriented communications over a substation LAN.

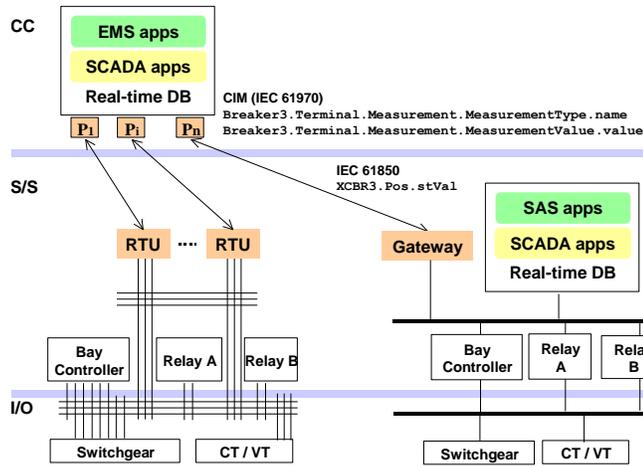


Figure 1 – Communications between control centre and substation

Data exchange between the control centre and the substation relies on one or more so-called RTU protocols (e.g., IEC 60870-101/104, DNP3.0, etc.). The protocol conversion is schematically shown in Figure 1 with boxes P₁, P₂ and P_n on the control centre system side, which typically has to support several RTU protocols. The gateways of modern SAS emulate the RTU, by converting the substation LAN protocol to an RTU one, as expected by a control centre.

Finally, Figure 1 shows the example data mappings between the CIM and the IEC 61850 data model for the breaker, introduced in the previous sections.

In the context of the topology-related data exchange between a control centre and the substations, we could identify three integration scenarios.

A. Configuration (data engineering or signal engineering)

At systems configuration time, either the CIMXML description of a particular substation can be transformed into SCL and used in the SAS, or vice versa, the SCL description of the substation can be converted into a partial CIMXML model and used in the control centre for configuration purposes. For a semi-automatic converter prototype, see [3]. Hypothesis is, of course, that the substation system understands the IEC 61850 data model, and that the control centre system understands CIM.

The data relevant for configuration is of two kinds:

(a) The data describing the functional structure of the substation and its connectivity is described in a serialisation format (SCL or CIMXML instance file). This is typical data needed for a single-line diagram, describing the layout of the primary equipment (breakers, switches, lines, busbars, power transformers) and how they are connected. This includes the place of measurement transformers (in SCL), translated into Measurement concept of CIM. The mapping between the CIM and the IEC 61850 data model is on the level of types of equipment (i.e., breaker - circuit breaker, line - line, measurement - measurement transformer, etc.); and,

(b) The mappings of concepts representing data points or signals in the two models. This kind of information should rely

on a standardised mapping between attributes of types. Examples for this type of mapping have been given above for a breaker and its position. Given the standardised mappings, it would be easy to configure communications links between the SCADA's process control unit and the substation gateway or RTUs (e.g., by automatically generating the pairs of addresses).

Given the standardised mappings between control centre and substation data models, even if a control centre system does not fully implement the CIM APIs and the substation system does not fully implement IEC 61850 services, the configuration process of one system can be highly automated from the description given by the other system, because it can be done through file exchange.

B. Run-time: Full integration

This scenario implies that the communications front-ends at both sides (control centre and substation) run on the same protocol – either the one specified by IEC 61850 (MMS stack that implements ACSI services) or some higher-level standard messaging mechanism such as CORBA (over IIOP) or Web Services (over HTTP/TCP/IP), which is a free choice according to IEC 61970. It is unlikely to have this latter case, due to the performance requirements of run-time data exchange between the substation and the control centre, and the limitations in the link bandwidth. Therefore, the most plausible case is the former, and the pre-conditions for this scenario are as follows:

- Both systems' communications front-ends "understand" their respective data models and have been configured as described in Subsection A above.
- At least the gateway of the substation system or the RTUs (see Figure 1) run on IEC 61850, i.e., they provide the concrete implementation of ACSI services (e.g., on MMS stack). Note that in an ideal case, the substation LAN would be IEC 61850, but this is not a requirement here.
- The process communications unit in the control centre implements IEC 61850 as one of its protocols (e.g., P_n in Figure 1). In the case where the substation LAN is IEC 61850, the gateway would be superfluous from the perspective of the control centre.

In this scenario, the substation system need not know anything about CIM, but the control centre system must know how to transform the IEC 61850 data model into CIM. The substation is the IEC 61850 server, and the control centre is the IEC 61850 client. Therefore, the process communications unit at control centre has to implement the minimum set of ACSI services, as specified for the client compliance to IEC 61850.

There are in general two possible approaches for a control centre to receive topology data at run-time: (a) request-reply mode, i.e., to poll all the status values of positions of switching equipment in the substation at regular time intervals, and (b) publish-subscribe mode, i.e., to subscribe to receiving only those values of positions that have changed, as soon as they change. Several ACSI services of IEC 61850 support both

request-reply and publish-subscribe mode of querying data values, and a control centre needs to implement, as a client, only those that it intends to use.

C. Run-time: Integration through file exchange

This integration scenario is an intermediate solution, which can be used as a first step towards the full run-time integration described in Subsection B above. The substation system periodically generates a partial CIMXML model, which contains the status values of positions of switching equipment. The values contained could be either all of them at the time of creation of the partial CIMXML file, or only those that have changed since the last creation of the partial CIMXML file. This decision is to be taken at systems configuration time.

The pre-conditions for this scenario are as follows:

- Both systems' communications front-ends "understand" their respective data models and have been configured as described in Section IV.A; and,
- Both systems' communications front-ends support some kind of file exchange (e.g., over FTP); and,
- Operating conditions are normal (secure state).

This scenario would be sufficient to refresh the real-time database of the control centre system for SE and TP applications, which are run typically every 5 to 60 minutes under normal operating conditions (this depends on the utility's policy and the control centre SCADA capabilities). However, this scenario does not make sense during abnormal operating conditions. Its usefulness is mainly as the first step towards the migration to full run-time integration. Note, also, that for this scenario, it is not necessary to have either side implement any particular protocol (except for file exchange), which means that the existing run-time systems would only need to be interfaced locally to get their respective data. However, the file processing is still needed at the substation. An independent conversion tool could perform the decoding of IEC 61850 data and the generation of partial CIMXML file [3].

V. CONCLUSIONS

The following conclusions may be drawn based on the discussion given in this paper:

- Existing EMS applications as well as future substation and

EMS applications can benefit from the ability to exchange data based on the standardised domain semantics.

- IEC 61850 and IEC 61970 provide a solid foundation for developing the required data exchange interfaces between the substation and the control centre SCADA, but currently do not allow for a straightforward implementation.
- The mapping tasks discussed in the paper and some of the proposed solutions (data exchange scenarios) may provide sufficient level of detail for future definition of the standards extensions, as required for data exchange.

VI. REFERENCES

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